API Comments on: *Sequestering Carbon Dioxide in a Closed Underground Volume*[1,2]

Background:

In their paper presented to the Society of Petroleum Engineers in October 2009, Dr. Economides and Dr. Ehlig-Economides conclude that their analysis "renders geologic sequestration of CO_2 a profoundly non-feasible option for the management of CO_2 emissions." This paper includes a number of mis-statements and erroneous base assumptions which could lead readers to arrive at inappropriate conclusions regarding the role that CCS can play in addressing CO_2 emissions.

The authors' assumption of a "closed" reservoir is – in general – too limiting.

The authors are correct in stating that reservoir pressure limitations will often dictate the maximum storage capacity in a saline reservoir. Their assumption of a "closed" reservoir could be particularly useful in considering the area needed to conduct multiple, large-scale CO_2 storage projects in a basin, and even for a full macro-scale analysis of CO_2 storage capacity in a basin.

However, the fundamental premise of the paper - that sequestration at the individual project-level will occur in "closed underground volumes" - can be characterized as very conservative, bordering on unrealistic. By making this assumption, the authors are effectively characterizing all geologic formations used for CO_2 storage as sealed, pressure tight containers with storage capacities limited by pressure constraints. While this condition can occur, it is unrealistic to assume it as the "baseline" condition in all potential storage reservoirs.

The oil and gas industry's vast experience clearly shows that truly closed reservoirs are relatively uncommon. Industry experience shows that a majority of producing geologic formations have some form of pressure communication across very broad areas. There is little reason to expect significantly different conditions (i.e. the supposed pressure containment) in saline portions of those same geologic formations or saline reservoirs that under- or over-lay those same formations.

The authors' assumption of a 200 ft thick reservoir is also too limiting.

The authors' section "Application for a Single Power Plant" indicates that for a reservoir of 200 ft thickness (plus other stated assumptions) where reservoir pressure is allowed to increase by 1000 psi (a reasonable assumption), an area of 686 mi^2 would be required to store the 90 MMTe CO_2 captured from a single 500 MW coal-fired power plant over its 30-year life. However, applying their method to an area such as the Mt. Simon formation in the Illinois basin, where reservoir thickness is commonly 1000 ft or more, an area of around 150 mi^2 would be required. This is close to 100,000 acres, around the scale that has been discussed for a "large-scale" storage project.

When realistic reservoir thickness is assumed – even without addressing the "closed" reservoir assumption – their conclusions are reversed.

As shown above, the authors' method yields a reasonable estimate of the size of reservoir needed for a project – again recalling the assumption of a closed reservoir. Taking the analysis a step further, we can consider the implications for the CO_2 to be stored in the US between today and 2050. The graph below illustrates that, given assumptions drawn from accepted projections by G8, EPRI and IEA, around 16 gigatonnes of CO_2 will need to be stored in the US in order to reach GHG emissions reduction goals envisioned in current US legislation. If all this CO_2 were to be stored in the Illinois basin, based on the calculations above, around 23,500 mi^2 of storage space would be utilized, or around 40% of the area of Illinois. This indicates that the Mt. Simon formation in the Illinois basin – just one of many prospective storage sites in the US – is sufficiently large to store all the CO_2 required to be eliminated through CCS

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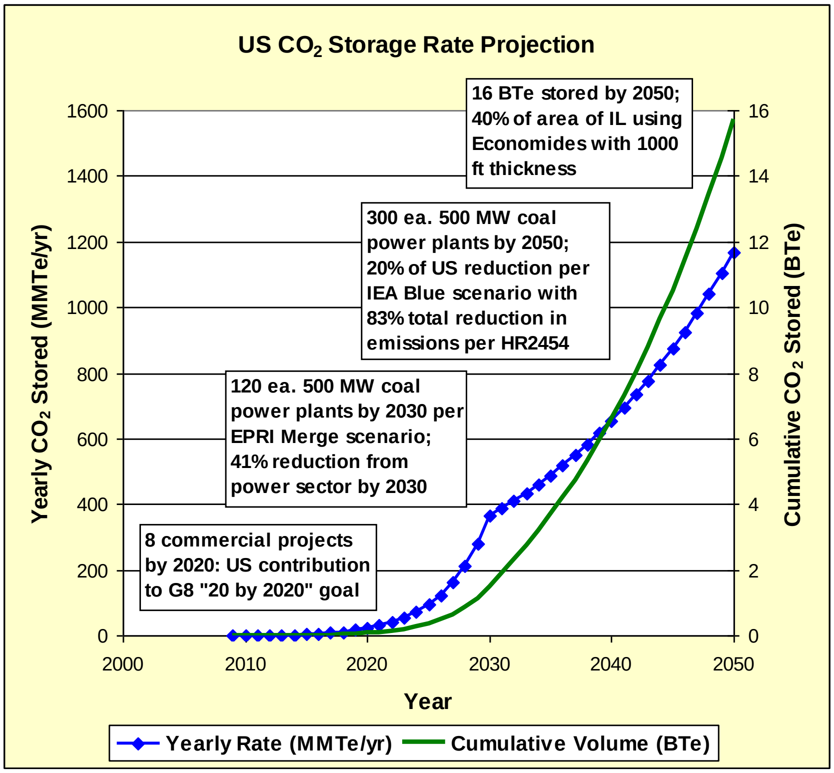
[1] Economides and Ehlig-Economides, 2009 SPE 124430 (presented at 2009 SPE Annual Technical Conference, New Orleans, LA. 4-7 October.

[2] Although these comments are based on the SPE article, they apply equally to the identical paper published in the Journal of Petroleum Science and Engineering (Ehlig-Economides, C. and M. J. Economides. "Sequestering Carbon Dioxide in a Closed Underground Volume." *J. Petrol. Sci. Eng.* **70**(1-2):123-130)

between today and 2050. *The authors' analytical method can therefore be utilized to prove the opposite conclusion to the one they make in the paper; namely, that management of CO_2 emissions through utilization of CCS in a portfolio of energy technologies is eminently feasible.*



<u>The authors' statements regarding storage efficiency and processes are puzzling.</u>
In their abstract, the authors state that the amount of CO_2 to be stored will not exceed 1% of pore space, and "[t]his will require from 5 to 20 times more underground reservoir volume than has been envisioned by many". This conclusion is puzzling. Most investigators have estimated that CO_2 will be able to occupy 2-3% of pore space, whereas in their paper (Fig. 3) the authors indicate CO_2 storage efficiency of 0.6-1%, depending on depth. This amounts to a discrepancy of 2-3 times, not the 5-20 times referenced in the abstract.

This 2-3x discrepancy can be explained by the different focus of the authors vis-à-vis other investigators. Others have considered the fraction of pore space that CO_2 will occupy, whereas the authors focus on the pressure space required to allow the storage of the CO_2. This pressure space approach may in fact be more appropriate when considering CO_2 storage capacity, but it neither invalidates the conclusions made by others, nor are the facts consistent with the alarmist conclusion made in the abstract.

Additionally, the authors' dismiss the additional capacity provided by CO_2 solubility into water stating that it is "a woefully slow process." The dissolution of CO_2 into brine is not a "woefully slow process"; it is a process that start almost immediately upon injection of CO_2 and its exposure to the native formation water. That process continues over the life of the injection project (10-50 or more years) and beyond.

Lastly, the author's interpretation that since natural gas storage operators cannot recover all of the gas they have injected is "an indication that some of the stored gas has leaked out of the reservoir" and that "exactly the same result may occur for CO2 storage…" (pg 4, ¶ 7) is most likely incorrect since it ignores the process of capillary trapping.

The statement that an "outcropping aquifer would provide a potential path for injected CO_2 to escape back to the atmosphere, thereby defeating the purpose of CO_2 sequestration" (pg 3, ¶ 4) is false.

The fact that a potential CO_2 storage formation outcrops does not assure a pathway for CO_2 leakage to the atmosphere. Many oil and gas producing formations outcrop at the surface; yet natural release of hydrocarbons at outcrops is very rare. The reason is that the oil and gas are trapped in the formations due to structural or stratigraphic features (anticlines, pinch-outs, etc.) of these formations underground (It is important to note in light of the author's earlier comments, that these features are not necessarily pressure sealing, rather they provide topographic elevations where the lighter density oil and gas are held). One proposed form of CO_2 storage would be placement of CO_2 in similar structural or stratagraphic features, commonly called traps. The rigorous storage site selection and review procedures envisioned by regulatory agencies are clearly targeted at avoiding approval of a storage site that has any significant identifiable path of leakage, whether through outcrops, faults, abandoned wells or other means.

Additionally, it appears that the authors are not familiar with the saline formations currently being targeted for CO_2 storage. *Probably most, if not all, of the identified target formations for sequestration in the US do outcrop somewhere.* The Knox formation outcrops in Tennessee; The Frio formation outcrops all through Texas about 3 counties inland from the coast; and the Mt. Simon formation outcrops in Wisconsin. And yet these formations are known to hold hydrocarbon accumulations and/or gas storage fields, without significant leaks to the surface, for millions of years. This indicates that local trapping mechanisms can create separate compartments for holding fluids while the overall formation is in pressure communication with the atmosphere where it is exposed to the surface. Even in structurally unconstrained situations, CO_2 migration will eventually cease as the CO_2 is trapped as residual saturation and/or dissolved in formation water.

Saline reservoirs can be properly appraised for CO_2 storage.

The authors use an oversimplified example of a pressure buildup/falloff test with the apparent intent to demonstrate that saline reservoirs of appropriate size for a large-scale CO_2 injection project can never be properly appraised. It is true that a single well is unlikely to provide enough reservoir data to characterize the storage volume for a large-scale project. However, this incomplete discussion does not address the many tools and techniques proven through oil and gas appraisal to address uncertainty in a large field development. Techniques such as 3D seismic, multi-well pressure interference tests and targeting wells to reduce key uncertainties are used routinely to prove up oil and gas fields that involve areal extents and financial investments at similar scales to those envisioned in CO_2 storage.

The authors' overstate the inappropriateness of comparing storage in saline reservoirs with storage in depleted hydrocarbon reservoirs or enhance oil recovery (EOR).

While API generally agrees with the authors' concerns, clarification is necessary. CCS proponents recognize that there are significant differences between storage in saline reservoirs, storage in depleted oil and gas reservoirs and storage with EOR and take exception to the suggestion that these differences are being ignored. From the oil and gas perspective, we can identify examples of each approach that can serve as viable analogies for CCS. The oil and gas industry strongly feels our experience can provide valuable insight and guidance to the sound development of CCS, rather than being ignored as the authors imply.

CO_2 storage capacity through enhanced oil recovery is greater than stated in the paper.

The authors' discussion regarding the potential contribution of CO_2 EOR contains errors that lead the authors to nonsensical conclusions. "With total (not annual) US oil reserves currently estimated by the EIA at 21.5 billion barrels, even if 10% of this could be enhanced via carbon dioxide injection, the amount would represent on the order of 2 billion barrels, which would represent just over the Kyoto Protocol target of 1.75 billion tonnes (14.4 trillion barrels) for annual (not total) carbon dioxide reduction." (page 2, ¶ 8)

The assumption that there is some type of relationship between proven reserves (21.5 billion barrels) and EOR potential and hence the viability of EOR as a substantial form of CCS is misleading. Reserves are defined as oil that is proven recoverable with currently available technologies. In other words, this is oil that will be produced without CO_2 to enhance recovery.

A more accepted approach is to look at the recovery potential based on the total remaining oil in place – that which is not currently recoverable. A recent study by the USDOE[3] identified about 390 billion barrels of remaining oil in place in 1,581 large US oil reservoirs. This report suggests as much as 47 billion barrels of oil may be economically recoverable while storing 8 billion tonnes of CO_2. While API feels these values may represent a "high side" estimate, the report illustrates the more commonly accepted method of determining incrementally recoverable oil using EOR.

<u>The potential for CO_2 storage in depleted gas fields is greater than the authors acknowledge.</u>
The authors dismiss the use of depleted gas reservoirs for CO_2 storage because "typically such reservoirs are used for natural gas storage and would not be available for carbon dioxide sequestration" (page 2, ¶10). According to the EIA, there were a total of 326 gas storage facilities in depleted natural gas or oil fields in the US in 2007, while there were over 15,000 natural gas producing fields in the US. Historically, the number of underground gas storage facilities has been growing at a slow but steady rate of less than 5 new facilities per year. At this rate, it is highly unlikely that the majority of depleted gas storage fields will be used for gas storage facilities any time in the future. Further, the largest natural gas storage facilities are on the order of 100-200 Bcf – clearly, the largest gas fields in the US are not being used for natural gas storage. Thousands of depleted gas fields in the US are potentially available for CO_2 storage.

<u>The authors' rejection of the analogy of water injection is unwarranted.</u>
That authors' state that "As another comparison, the US currently injects about 38 million bpd of oilfield water. Although this may appear to be a reassuring analogy to the CO_2 volume, in reality it is not, because oilfield water is typically injected in hydraulic communication with the oil and gas production to achieve pressure maintenance…" (pg. 2, ¶3).

A recent report published by the USDOE[4] provided a more accurate description of produced water (oilfield water) handling. Key points include:

- In 2007, produced water production associated with oil and gas was 57.4 million barrels per day (Mbpd).
- 95% of this volume, 54.5 Mbpd is injected, 3% is discharged offshore, and 2% is handled in "other" ways.
- 40% of the water, 21.8 Mbpd, is injected into "non-producing" formations.

"Non-producing" formations typically are formations that either over- or under-lay the producing formations in an oil or gas field. These formations normally do not have any hydraulic connection or communication with the producing formation. As shown by the referenced report, substantial volumes of oilfield water are being injected into these formations, where the injection is not replacing the fluids that have been produced, without apparent adverse effect (lack of effect is implied by the scale of the activity). This activity has been common industry practice for well over 50 years, (starting in some areas as early as the 1930's) without evidence of adverse impact. This scenario closely resembles the situation envisioned for CO_2 injection into saline reservoirs and is occurring at volumes of the same order of magnitude anticipated with the full scale implementation of CCS.

<u>The author's statement that the Sleipner CO_2 injection project has seen "significant leakage into overlying layers" is not accurate. (pg 4, ¶ 3)</u>
The authors reference a paper on the Sleipner CO_2 injection project and state that there was "significant leakage to overlying layers." The Sleipner injection project in the North Sea is one of the most closely monitored CO_2 injection projects underway today. Injection of CO_2 occurs at the base of the Utsira sandstone reservoir. Originally, the project proponents considered the storage formation to be a large homogeneous formation and that the CO_2 would vertically fill the formation fairly uniformly. What has

[3] Advanced Resources International, "Basin Oriented Strategies for CO_2 Enhance Oil Recovery", prepared for the USDOE, Office of Fossil Energy, April 2005
[4] Clark, C. E., Veil, J. A., "Produced Water Volumes and Management Practices in the United States", Report by Argonne National Laboratory for the USDOE, Office of Fossil Energy, ANL/EVS/R-09/1

been observed over the last ten years, however, is that even relatively minor heterogeneities can significantly affect the movement of the CO_2 in the formation, leading to a more layered distribution of CO_2 in the formation than was originally anticipated. The fundamental containment of CO_2 in the storage formation has not been compromised; nor does pressure in the reservoir appear to be increasing at an unacceptable rate.

The authors also state that the relative permeability of CO_2 was "significantly reduced" based on their reading of the reference paper. The reference paper (Bickle, et al) is a modeling study on Sleipner using 4D seismic to image the plume and calculate CO_2 volume and movement in the subsurface. The authors of the referenced paper clearly state in the conclusions that the difference in measured permeabilities to model-calculated permeabilities could be due to: 1) limitations in the model (reservoir temperature is mentioned as a major uncertainty, which strongly influences CO_2 physical properties), 2) permeability differences due to scale of measurements (core data vs. whole reservoir), or 3) less CO_2 is stored in layers than estimated from seismic. The authors conclude that the most probable cause for the apparent permeability differences is that the relative permeability to CO_2 is significantly reduced at lower CO_2 saturations (not fully stated in Economides paper). Others (Lumley, et al, 2008)[5] have questioned the seismic data, implying that the multiple layers of CO_2 observed in the seismic may actually be imaging artifacts, adding more uncertainty to this conclusion.

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[5] Lumley, D., Adams, D., Wright, R., Markus, D., and Cole, S., "Seismic monitoring of CO2 geo-sequestration: realistic capabilities and limitation", SEG Expanded Abstracts 27, 2841 (2008)